System Operator Reports
January 2015

Contents

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

System Operator Operational and System Performance Report to the Electricity Authority in relation to 1 to 31 January 2015

Purpose of Report

This report summarises Transpower's review of its performance as system operator for the period 1 to 31 January 2015, as required under clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

Any relevant operational issues are also provided for the information of the Electricity Authority (the Authority). A separate detailed System Performance report will be provided to Authority staff.

1. Summary of Month from an Operational and System Performance Perspective

1.1. Operational

January 2015 was characterised by fine, warm and still conditions across the country. Managing voltage during low demand periods (often with reduced thermal and wind generation) requires more active and regular co-ordinator action than in non-holiday months especially into the upper North Island. This included removing the Pakuranga_Whakamaru (PAK_WKM) circuits (one of which was on continuous outage for two weeks across the Christmas/New year period) as a cost effective way to manage high system voltages with low demand.

System events

There were few system events in January 2015. An unplanned outage, on 18 January 2015, due to the tripping of Kinleith (KIN) T2 resulted in lost load of 21.2MW (including the entire Kinleith mill). Although the outage was not prolonged (service was progressively restored from 06:09), mill operations did not return to full production for several days.

HVDC Reserves Capability Modelling Change

On 17 December 2014 the HVDC reserve sharing modelled in the Reserve Management Tool (RMT) was increased to 60MW of FIR year-round, from 50MW winter and 25MW summer. This appears to have contributed to a significant reduction in instantaneous reserves costs as noted later in the report.

FKC operational trials

The system operator's frequency keeping control (FKC) trial continued (apart from a one hour period on 7 January 2015 when an unplanned outage of Pole 2 meant FKC was switched off). Current FKC trial settings are: 40MW HVDC modulation risk band and 30MW frequency keeping band (NI 20MW and SI 10MW). The trial will continue, with a test of a 0MW frequency keeping band in February. The trial is on target for completion by the end of March 2015.

One impact of the trial has been an ongoing reduction in the cost of ancillary services as described later in this report.

Clyde Roxburgh upgrade work

Completing the upgrade work on the Clyde to Roxburgh circuits required the Roxburgh import overload protection scheme to be enabled on 13 January 2015. This scheme enhances transmission transfer into the south of the South Island reducing the generation required from the Clutha and Manapouri hydro schemes during the outages for circuit re-conductoring. The re-conductoring work is expected to be complete by 20 February.

1.2. Market

There were no outages to the market systems during January 2015 which exceeded two hours in duration. The system operator dispatched from its stand-alone dispatch (SAD) application twice during January 2015:

1. on January 28 (less than one trading period) when a market system application briefly faulted; and

2. on January 29 (slightly over two trading periods) for a planned (and notified) maintenance outage.

2. Business Performance

Significant Project Update

The Reserves and Frequency Management programme is progressing to the agreed timetable with the Authority. The status of the component projects are as follows:

- South Island Multiple Frequency Keeping is now live with project close out complete;
- Reserve Management Tool TSAT Implementation is complete and in the project close-out phase;
- Security Tool Implementation solution design is underway, with the Delivery Business Case complete and undergoing final review for approval;
- Inter-island Instantaneous Reserve Sharing was implemented for FIR in December. Scope changes have been approved and work on this new scope is progressing well;
- Feedback from the National Market for Instantaneous Reserve information paper is due on 17 February 2015. TASC 048 for the Develop Solution Approach has been approved, with work commencing in January;
- The National Market for Frequency Keeping scope is being reviewed as part of TASC 049 (Frequency Management Strategy);
- Efficient Procurement of Extended Reserves Implementation is on hold pending the appointment of an ‘Extended Reserve Manager’ by the Authority (which we understand to be imminent); and
- The Revised Instantaneous Reserve Markets TASC brief is progressing with workshops underway.

3. Security of Supply Update

NZ aggregate storage levels are 95% of average for this time of year. The hydro risk meter is currently set at “normal”. In the unlikely event of significant equipment failure, the Security of Supply status could change quickly.

4. Compliance Report

There were no breaches of the principal performance obligations by the system operator during January 2015.

There were two breaches of the Code reported to the Authority during January 2015, being:

- a HVDC modelling error, which was identified and corrected in the long schedules prior to real time; and

- a grid modelling error, which delayed the production and publication of a long schedule within the stipulated timeframe.

5. Ancillary Services

The system operator has been working with Trustpower to carry out testing at Patea in preparation for its entry into the multiple frequency keeping market. Patea should be in the market as soon as analysis of the test data has been completed.

The system operator has also been working with Mighty River Power to rectify issues that came to light during the recent black start test at Maraetai. A limited scope retest is intended to be carried out in February 2015.

Ancillary Service Costs

The costs of ancillary services for the month of January 2015 are set out in Appendix A (as required by clause 82.1 of the Procurement Plan).

There has continued to be a downward trend in frequency keeping costs during January. These costs are now at the lowest level seen since December 2000. This is attributable to the reduction in the amount of frequency keeping required to be purchased as a result of the ongoing HVDC frequency keeping controller trial.

Instantaneous reserve costs were also very low during the month. The reasons for this are less clear, but are likely to be partly reflective of market conditions and partly attributable to Transpower's decision to increase the HVDC's reserve sharing capability from 25MW to 60MW.

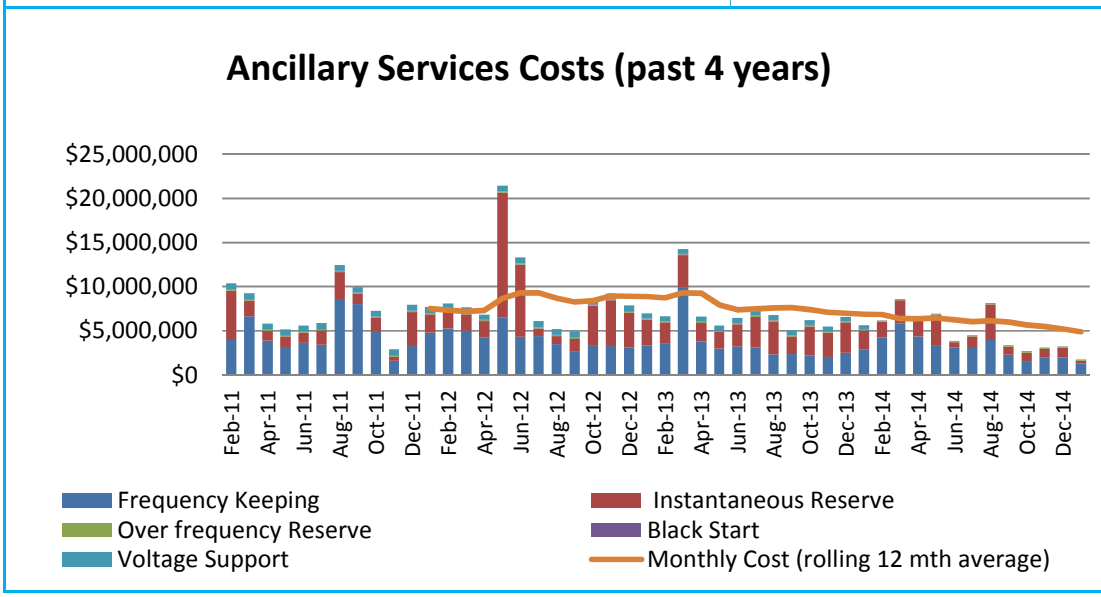
6. Code 7.10: Separation of Transpower Roles

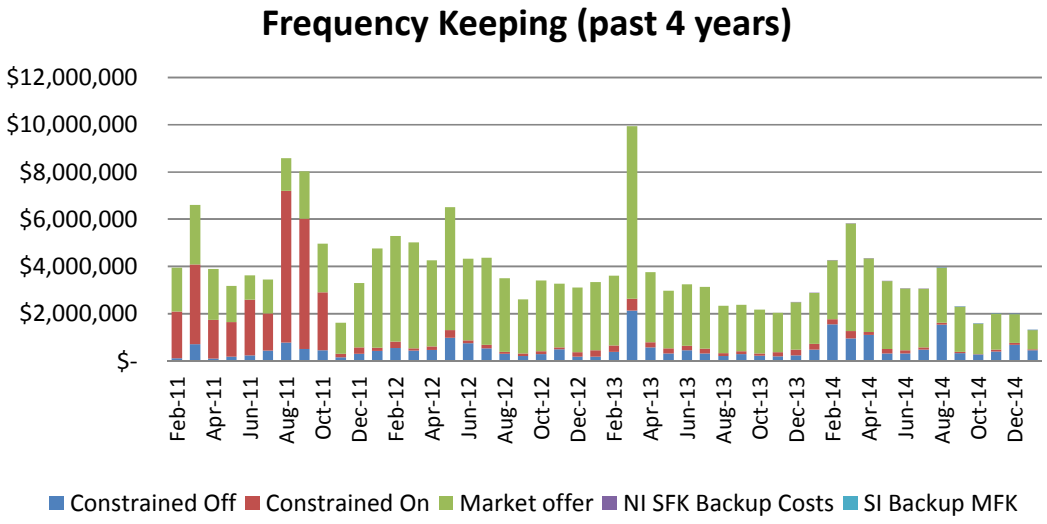
In performing its role as system operator, Transpower has not been materially affected by any other role or capacity Transpower has under the Code or under any agreement.

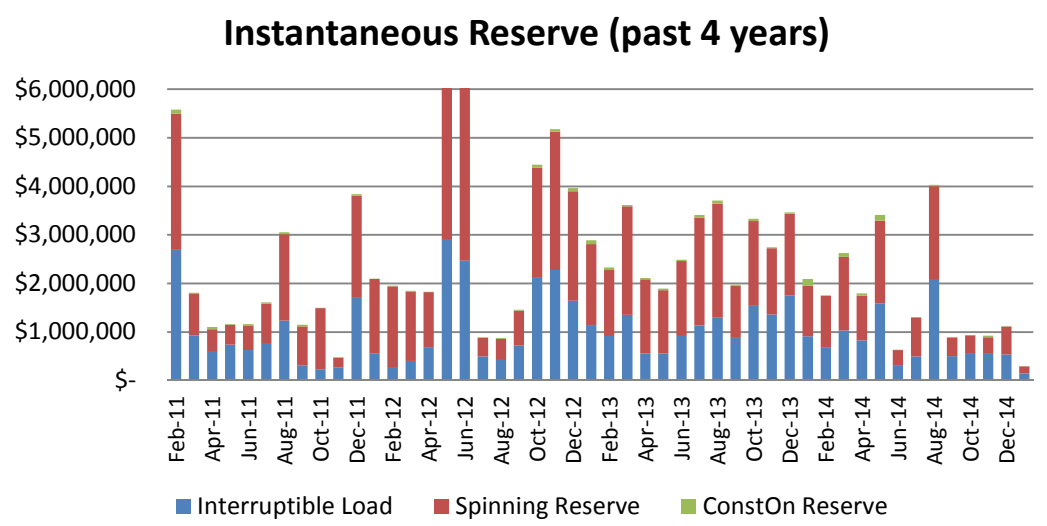
Appendix A – Ancillary Service Costs for January 2015

Note: The scale for the Instantaneous Reserve (Past 4 Years) graph has been reduced to clarify detail. Two months data, May and June 2012, overly influenced the graph scale.

		Cost	
Frequency Keeping	Constrained Off	$	459,984
	Constrained On	$	33,191
	Market offer	$	819,072
	NI SFK Backup Costs	$	2,716.67
	SI Backup MFK	$	2,232.00
	Total monthly Cost	**$**	**1,317,196**
Instantaneous Reserve	Spinning reserve	$	145,713
	Interruptible Load	$	149,265
	Constrained On	$	1,876
	Total monthly Cost	**$**	**296,854**
Over Frequency Reserve	**Total monthly Cost**	**$**	**113,842**
Black Start	**Total monthly Cost**	**$**	**37,468**
Voltage Support	**Total monthly Cost**	**$**	**-**
All Ancillary Services	**Total monthly Cost**	**$**	**1,765,359**







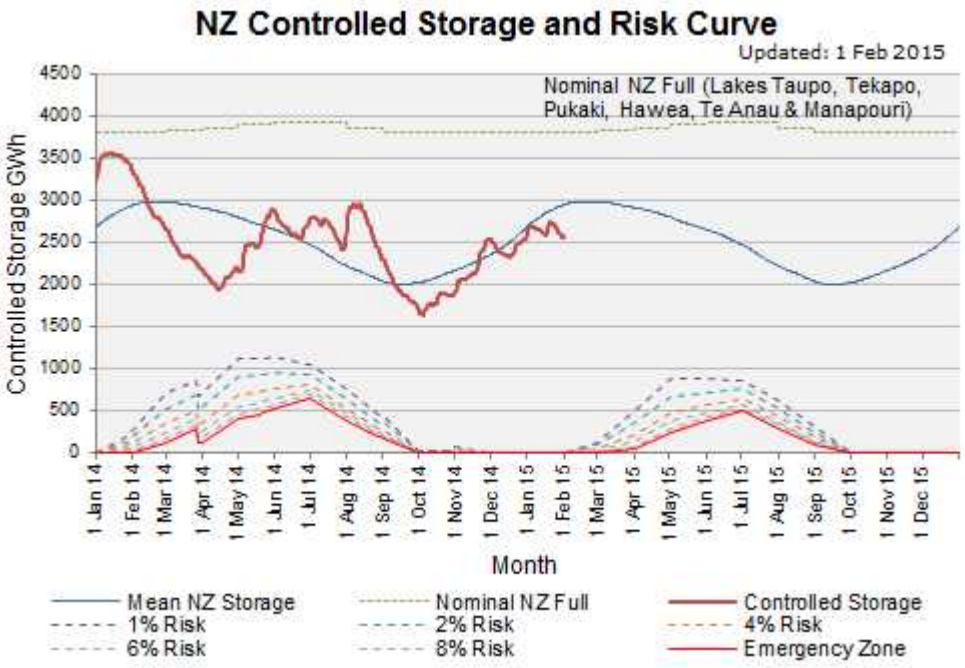
Note: IR Cost May 2012 = 14.129M, IR Cost Jun 2012 = 8.164M

Appendix B – Security of Supply

New Zealand Hydro Storage and Hydro Risk Curves

As at 9 February 2015, aggregate primary New Zealand storage is 95% of average.

The graph below compares New Zealand hydro storage to the hydro risk curves.



Hydro Storage and Generation

North Island inflows over the month of January 2015 have been 58% of average.

South Island inflows over the month of January 2015 have been 82% of average.

Measurements are based on daily inflow values.

Hydro generation met 59% of demand during January 2015.

System Performance Report

To the Electricity Authority

January 2015

Purpose

This System Performance Report summarises power system performance each month. The detailed reporting of system events is intended to provide an understanding of the nature of system events that occur in the normal course of the real time co-ordination of security and to identify emerging issues in system operation.

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

Transpower New Zealand Ltd The National Grid

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1. Summary of System Performance

This system performance report covers the month of January 2015.

Principal Performance Obligations

The system operator met the Principal Performance Obligations during the reporting period.

System Events

On 6th January at 13:46 Stratford power station units U21 & U22 tripped, resulting in a momentary drop in frequency in the North Island to 49.43 Hz.

The only other noteworthy events occurring during the reporting period were faults on the 220 kV Bunnythorpe – Brunswick Circuit 1 at 12:51 and 12:52 on 28 January 2015, which caused commutation failures on the HVDC. This resulted in voltage disturbances throughout the lower North Island.

2. Principal Performance Obligations

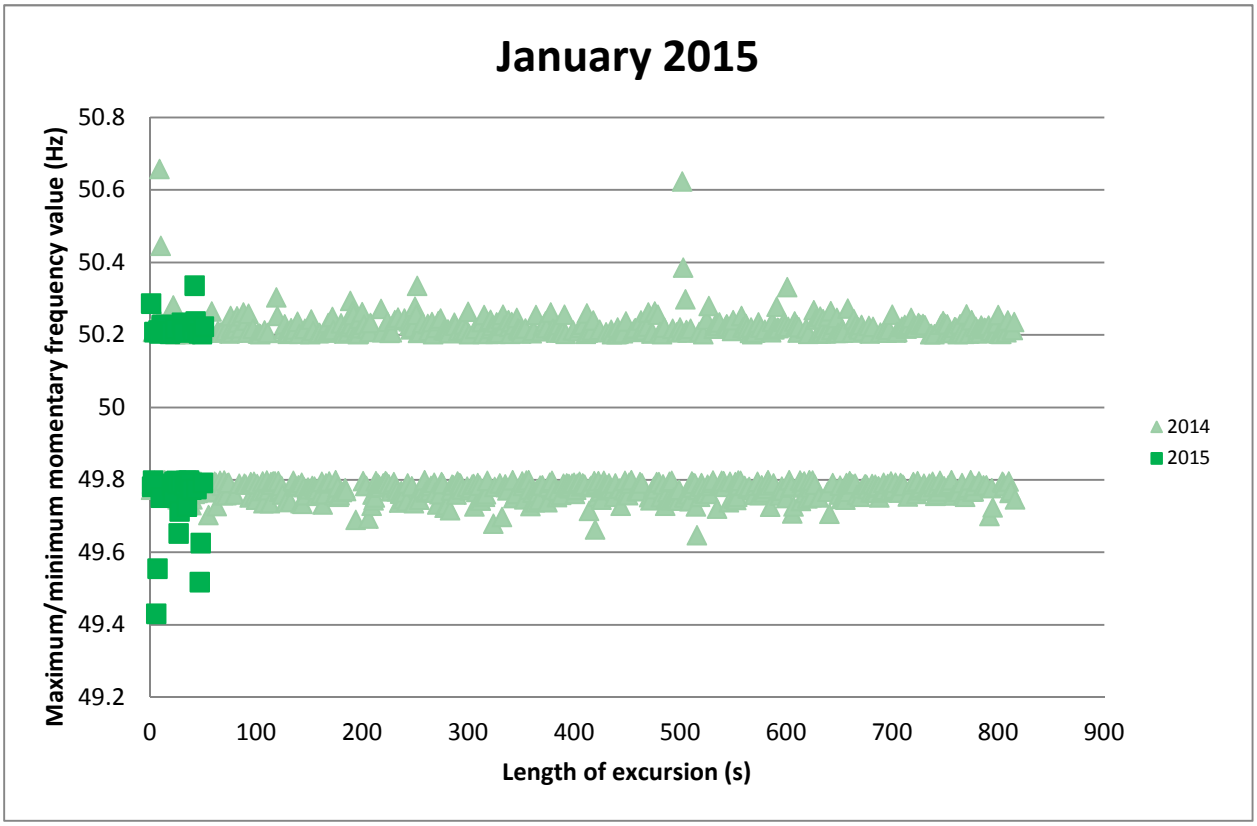
2.1 Avoid Cascade Failure

No instances of cascade failure occurred during the reporting period.

2.2 Frequency

Maintain frequency in normal band and recover quickly from a fluctuation

The chart below shows the maximum or minimum frequency reached and length of each frequency excursion outside the normal band (49.8 to 50.2 Hz) during the reporting period. The majority of excursions are within 0.4 Hz of the normal band and frequency typically returns to within the normal band within 2 minutes.



Maintain Frequency and limit rate occurrences during momentary fluctuations

The table below shows the total number of momentary fluctuations outside the frequency normal band, recorded in both Islands, over the last 12 months. The 12 month cumulative totals, grouped by frequency band, are compared to the frequency performance objective (PPO).

Frequency Band	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Annual rate	PPO target
55.00 > Freq >= 53.75														**0.2***
53.75 > Freq >= 52.00														**2***
52.00 > Freq >= 51.25	3												**3**	**7**
51.25 > Freq >= 50.50		1	0	1	1	1	1	1		2			**8**	**50**
50.50 > Freq >= 50.20	333	398	545	430	206	336	345	420	244	360	165	26	**3808**	
50.20 > Freq > 49.80														
49.80 >= Freq > 49.50	386	610	639	485	208	452	401	585	351	375	204	24	**4720**	
49.50 >= Freq > 48.75	3	1	2				1		2	5	2	1	**17**	**60**
48.75 >= Freq > 48.00										1			**1**	**6**
48.00 >= Freq > 47.00														**0.2**
47.00 >= Freq > 45.00														**0.2**

***** South Island

Manage time error and eliminate time error once per day

The time error performance criteria are:

Time error must be managed within +/- 5 seconds.

Time error must be eliminated at least once every day.

Time Error Compliance Table		Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
Time Error Management	NI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	SI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Time Error Elimination	NI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	SI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

3. Operational Management

3.1 Security Notices

The following table shows the number of Warning Notices, Grid Emergency Notices and Customer Advice Notices issued over the last 12 months.

Notices issued	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	9	5	14	19	12	5	4	3	7	3	5	1
Warning Notice	-	-	-	1	-	8	21	7	8	11	23	29
Customer Advice Notice	12	18	24	17	4	33	16	10	28	22	20	11

3.2 GRID EMERGENCIES

The following table shows grid emergencies declared by the system operator in the reporting period.

Date	Time	Summary Details	Island
08/01/15	19:06	A grid emergency was declared to close the 110 kV Arapuni Bus split due to an electrical storm in the vicinity.	N

A summary of grid emergencies that have occurred in the last 12 months is shown in the following table.

Island	Region	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Total
North Island	Northland	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Auckland	-	-	-	-	-	-	-	-	4	-	-	-	**4**
	Zone 1	8	3	7	8	6	3	1	-	-	-	-	-	**36**
	Waikato	-	1	1	-	-	-	-	2	2	2	4	1	**13**
	Bay of Plenty	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Hawkes Bay	-	-	1	-	-	-	-	-	-	-	-	-	**1**
	Taranaki	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Bunnythorpe	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Wellington	-	-	-	-	-	1	-	-	-	-	-	-	**1**
	North Island (all)	1	1	-	-	-	1	-	-	-	-	-	-	**3**
	Lower North Island	-	-	-	1	1	-	1	-	-	-	-	-	**3**
North & South Islands		-	-	-	-	1	1	1	-	1	-	-	-	**4**
South Island & HVDC	Nelson Marlborough	-	-	-	-	1	-	-	-	-	-	-	-	**1**
	West Coast	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Christchurch	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Canterbury	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Zone 3	-	-	5	9	3	-	1	1	-	1	-	-	**20**
	Otago	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	Southland	-	-	-	-	-	-	-	-	-	-	-	-	**0**
	South Island (all)	-	-	-	-	-	-	-	-	-	-	1	-	**1**
	HVDC	-	-	-	-	-	-	-	-	-	-	-	-	**0**

3.3 Customer Advice Notices (CANs)

Eleven CANs (Customer Advice Notices) were issued in the reporting period:

- two related to an unplanned outage of HVDC Pole 2;
- two related to temporary re-rating of the 220 kV Islington – Livingstone Circuit due to protection related issues;
- two advised of temporary changes to the HVDC risk subtractor due to planned outages at Haywards Substation;
- two advised that the system operator was dispatching from the back-up systems on 28 January;
- one advised HVDC Frequency Keeping Control would resume as the normal mode of operation from 15 January;
- one advised the Roxburgh Import Overload Protection Scheme will be enabled daily 00:00 to 05:00, to coincide with the 220 kV Clyde – Roxburgh 1 Outage for re-conductoring starting 12 January; and
- one advised of a manual constraint being implemented during a planned 220 kV Tekapo B – Twizel Circuit outage.

3.4 Standby Residual Check (SRC) notices

No SRC notices were issued during the reporting period based on the SDS (system operator's own load forecasting tool).

3.5 Voltage Management

Grid voltages did not exceed the Code voltage ranges during the reporting period.

3.6 Outage Management

The following table shows the number of outages over the last 12 months where operational measures (generation agreements, load management agreements or grid re-configurations) were required to allow the outage to proceed. Load agreements generally require the distributor to manage load at one or more grid exit points. Generation agreements are required to ensure that sufficient regional generation is available to provide energy or reactive support during the outage to maintain security standards. Grid re-configurations typically involve splitting the network during the outage to manage post contingency power flows. Security of supply is sometimes reduced by grid re-configuration.

Island	Region	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Total
North Island	Northland	7	8	4	8	6	-	1	2	5	3	3	3	**50**
	Auckland	1	5	-	12	5	2	3	6	4	3	1	1	**43**
	Waikato	9	12	12	12	6	3	5	10	10	9	3	4	**95**
	Bay of Plenty	2	7	5	6	5	5	5	-	6	7	6	3	**57**
	Hawkes Bay	4	6	12	5	-	1	-	-	5	2	2	2	**39**
	Taranaki	5	4	5	2	2	-	1	1	2	7	-	4	**33**
	Bunnythorpe	6	7	3	5	-	-	-	2	7	4	1	5	**40**
	Wellington	13	13	17	12	6	3	4	3	12	9	10	11	**113**
Total		47	62	58	62	30	14	19	24	51	44	26	33	**470**
South Island	Nelson Marlborough	3	7	5	4	7	5	2	4	10	14	8	7	**76**
	West Coast	2	11	6	7	7	10	6	4	10	11	8	8	**90**
	Christchurch	3	4	5	2	5	4	2	4	7	10	6	5	**57**
	Canterbury	2	4	3	2	5	4	4	2	6	7	4	4	**47**
	Otago	-	3	2	4	-	-	2	9	2	4	2	1	**29**
	Southland	2	6	2	8	6	5	5	2	1	3	3	1	**44**
Total		12	35	23	27	30	28	21	25	36	49	31	26	**343**

3.7 CONSTRAINTS

SUMMARY: Security constraints binding during the month

The following table shows the binding constraints during the reporting period.

Additional information on security constraints can be found on the following website address: *http://www.systemoperator.co.nz/security-management#cs-147305*. This information includes constraint equations and a brief summary of their purpose.

Island	Region	Branch	Description	Total
North Island	Hawkes Bay	FHL_RDF1.1__FHL_RDF2.1__FHL_RDF2__RDF__LN	This is an SFT generated constraint. Its purpose is to protect Fernhill-Redclyffe 1 for a tripping of Fernhill-Redclyffe 2.	1
		RDF_T3&T4_S_P_1	The effect of this constraint is to manage flows through Redclyffe T3 and T4 for a contingency of Redclyffe T4 or T3 during low Tuai generation.	14
South Island & HVDC	Christchurch	ISL_LIV.1__ASB_TIM_TWZ2.3__:S__ASB_TWZ2__ISL__LN	This is an SFT generated constraint. Its purpose is to protect Islington-Livingstone 1 for a tripping of Ashburton-Timaru-Twizel 2.	9
	Otago	NSY_ROX.1__CYD_ROX2.1__CYD_ROX2__ROX__LN	This is an SFT generated constraint. Its purpose is to protect Naseby-Roxburgh 1 for a tripping of Clyde-Roxburgh 2.	6
	Southland	BDE_GOR.1__INV_ROX1.1__INV_ROX1__GOR__LN	This is an SFT generated constraint. Its purpose is to protect Brydone-Gore 1 for a tripping of Invercargill-Roxburgh 1.	2
Grand Total				**32**

Constraints binding during last 12 months

The following table shows all binding constraints during the reporting period, which were binding for a duration of more than 4 trading periods and any constraints binding for more than 48 trading periods during the previous 12 months.

Island	Region	Constraint	Reporting period		Previous 12 months	
			Number of trading periods that constraint bound	Percentage of trading periods	Number of trading periods that constraint bound	Percentage of Trading periods
North Island	Hawkes Bay	RDF_T3&T4_S_P_1	14	0.94%	3	0.02%
South Island & HVDC	Christchurch	ISL_LIV.1__ASB_TIM_TWZ2.3__:S__ASB_TWZ2__ISL__LN	9	0.60%	0	0.00%
	West Coast	COL_HOR2.1__COL_HOR3.1__COL_HOR3__COL__LN	0	0.00%	54	0.31%
		COL_HOR3.1__COL_HOR2.1__COL_HOR2__COL__LN	0	0.00%	58	0.33%
	Otago	LIV_NSY.1__CYD_ROX1.1__CYDROX1!__NSY__LN	0	0.00%	61	0.35%
		LIV_NSY.1__CYD_ROX1.1__CYDROX1#__NSY__LN	0	0.00%	69	0.39%
		NSY_ROX.1__CYD_ROX2.1__CYD_ROX2__ROX__LN	6	0.40%	0	0.00%
	HVDC	BEN_HAYP2max	0	0.00%	120	0.68%

4. System Events

4.1 Significant System Events

The following table shows significant events (frequency excursions and connection point events), which occurred during the reporting period.

Significant frequency excursions

Date	Time	Summary Details	Island	Freq (Hz)
06/01/15	13:46	Stratford generating units U21 & 22 tripped resulting in a momentary drop in frequency in the North island.	N	49.43

Connection point events

Date	Time	Summary Details	Generation / Load interrupted (MW)	Restoration time (minutes)
		None.		

4.2 System Events during reporting period

System events that occurred during the reporting period are summarised below:

Contingent events

Event	Number	Summary
Loss of single AC transmission circuit	13	These related to trippings of • Arapuni-Hangatiki 1 • Arapuni-Hangatiki-Ongarue 1 (auto reclose) • Bunnythorpe-Marton-Wanganui 1 • Bunnythorpe-Paraparaumu-Haywards 2 (auto reclose) • Bunnythorpe-Tararua Central-Linton 1 • Edgecumbe-Kawerau 1 • Henderson-Maungatapere 2 (auto reclose) • Invercargill-Roxburgh 2 (auto reclose) • Islington-Livingstone 1 (3 x auto reclose) • Livingstone-Naseby 1 (auto reclose) • Timaru-Tekapo A 1 (switching error)
HVDC Start/Stop	1	This related to • Line protection operation on Pole 3 (pole blocks and auto-restarts)
Supply Transformer	2	These related to trippings of • Gisborne T2 • Kinleith T2
Loss of grid reactive plant	7	This related to tripping of • Albany Static Var Compensator SVC7 • Haywards Filter Bank F5B (2 x), Synchronous Condensor SC2 • Hokitika C7, C8, C9 (2 x) • Islington Static Var Compensator SVC9

Event	Number	Summary
Loss of single generation units	19	These related to trippings of • Kawerau Geothermal • Kapuni generation (2 x) • Matahina G1 • Mokai generation (3 x) • Ohaaki G2, G6 • Onepu TA3 (2 x) • Poihippi G1 • Rotokawa generation (4 x) • Rangipo G5 • Southdown GE105 • Wairakei G7
Total during reporting period	**42**	

Extended contingent events

Event	Number	Summary
Loss of both HVDC poles	0	
Loss of interconnecting transformer	0	
Loss of bus bar section	0	
Total during reporting period	**0**	

Other events

Event	Number	Summary
Loss of multiple AC transmission circuits	2	These related to • Bunnythorpe-Brunswick 1 auto reclose, resulting voltage disturbance caused a commutation failure on HVDC P2 & P3. • Bunnythorpe-Brunswick 1 trip, resulting voltage disturbance caused multiple commutation failures on HVDC P2.
Demand change	1	This related to • Motueka AUFLS tripping shed approx. 40% of demand (Motueka running islanded from the system supplied by Cobb at the time)
Generation	3	These related to trippings of • Cobb G1 & G5 • Stratford U21 & U22 • Tararua windfarm (Bunnythorpe & Linton connected stations)
Total during reporting period	**6**	

Other disturbances

Event	Number	Summary
Feeder trippings	41	Various locations
Total during reporting period	**41**	

4.3 SYSTEM EVENTS – TREND

	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Total	Average Events per month
Contingent Event – transmission	6	8	34	19	9	16	8	14	19	9	11	13	**166**	13.8
Contingent Event – generation	8	11	12	5	7	23	12	12	1	16	12	19	**138**	11.5
Contingent Event – Supply transformer	3	0	3	4	3	0	2	4	4	1	1	2	**27**	2.3
Contingent Event – Reactive plant	5	2	2	5	2	0	1	9	1	2	1	7	**37**	3.1
Contingent Event - HVDC	2	1	1	1	0	0	0	2	2	7	0	1	**17**	1.4
Extended Contingent Event HVDC	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0.0
Extended Contingent Event Inter-connecting Transformers	0	0	0	1	1	0	0	0	1	0	0	0	**3**	0.3
Extended Contingent Event Busbar	1	1	0	0	1	1	0	0	2	0	1	0	**7**	0.6
Other Event – AC transmission	1	0	6	2	1	1	1	0	2	3	0	2	**19**	1.6
Other Event – Demand	2	1	0	1	1	1	1	2	1	5	0	1	**16**	1.3
Other Event – Generation	0	0	0	0	0	0	1	2	1	1	0	3	**8**	0.7